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Financial accounting and reporting by oil and gas producing companies: Guidelines for application of FASB statement no. 19

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Guidelines for Application of FASB Statement No. 19

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INTRODUCTION

The issuance of Financial Accounting Standards Board (FASB) Statement No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies* (the Statement), has a significant accounting impact on most companies in the industry. The Statement eliminates alternative methods of accounting for costs incurred in searching for and developing oil and gas reserves and requires oil and gas producing companies to follow a form of the successful-efforts method. This will result in accounting changes by substantially all oil and gas companies, including those companies currently using a different form of successful-efforts accounting. The provisions of the Addendum to Accounting Principles Board (APB) Opinion No. 2, *Accounting for the Investment Credit,* should govern the application of the Statement to those oil and gas producing operations of a company that are regulated for ratemaking purposes on an individual-company-cost-of-service basis. The Statement is effective for fiscal years beginning after December 15, 1978 and for interim periods within those fiscal years. Companies reporting to the Securities and Exchange Commission (SEC) need to disclose the general magnitude of estimated financial statement effects in disclosures accompanying financial statements issued prior to adoption of the provisions of the Statement. Companies not reporting to the SEC will probably want to make a similar disclosure in their financial statements.

The following summary provides an overview of the major provisions of the Statement, which are discussed at greater length in this booklet:

- Requires oil and gas producing companies to use a form of the successful-efforts method of accounting for costs incurred in searching for and developing oil and gas reserves.
- Accounting requirements include the following:

  Decision to capitalize or expense an item is determined primarily by the nature of its cost rather than by reference to a cost center (such as an area-of-interest).

  Mineral interests in properties are recorded as assets when acquired.

  All exploration costs, except the costs of drilling exploratory wells, are charged to expense when incurred.

  The costs of drilling exploratory wells, including exploratory-type stratigraphic test wells, are capitalized as "wells-in-progress" when incurred, to be charged to expense later if the well is determined not to have found proved reserves or to be reclassified as an amortizable asset if proved reserves are discovered.

  - Special provisions apply if reserves are found by a well drilled offshore or in a remote area when classification of those reserves as proved cannot be made when drilling is completed.

After discovery of reserves, costs incurred to drill all development wells, including development-type stratigraphic test wells, are capitalized as amortizable assets.

After production begins, the capitalized acquisition, exploration, and development costs relating to reserves that were discovered are amortized, on a unit-of-production basis, as the reserves are produced.

- Amortization is based on proved reserves as to acquisition costs and on proved developed reserves as to capitalized exploratory drilling and development costs.
- For amortization purposes, properties may be grouped under certain conditions.
- Amortization and depreciation rates should take into account any estimated dismantlement, restoration and abandonment costs and estimated residual salvage value.

Unproved properties should be reviewed periodically for impairment and, if necessary, a valuation allowance provided.

Mineral property conveyances and related transactions, and surrender, abandonment or retirement of properties can result in recognition of gain or loss under specified conditions. Other aspects of accounting for these transactions are also discussed.

- Supersedes FASB Statement No. 9, *Accounting for Income Taxes—Oil and Gas Producing Companies.*

Comprehensive interperiod tax allocation by the deferred method, as described in APB Opinion No. 11, *Accounting for Income Taxes,* is required.

- The possibility that statutory depletion in future periods will reduce or eliminate the amount of income taxes otherwise payable should not be taken into account.

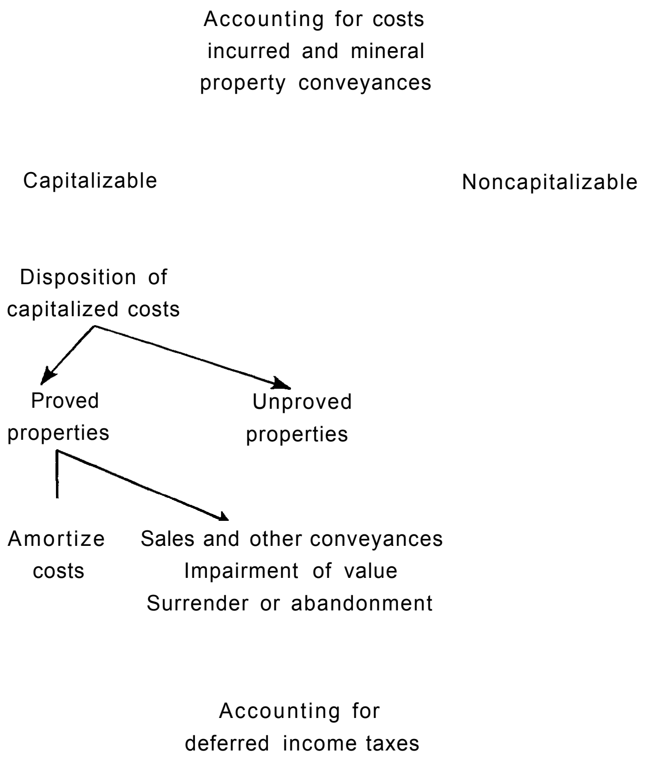
- Disclosures required include:

Quantities of proved reserves and proved developed reserves of oil and gas at the beginning and end of each year and changes in proved reserves during the year.

Costs incurred for property acquisition, exploration, development, and production.

Accounting changes necessary to adopt the financial accounting and reporting standards of the Statement are to be applied retroactively. This will require the use of estimates and approximations, some of which may not have been made previously. Information available after the year being restated may be taken into account in making such estimates, except that estimates of quantities of oil and gas reserves that had been made in prior years cannot currently be revised in retrospect. A provision of the Statement that would not have a significant effect on prior years' financial statements need not be retroactively applied, and the Statement does not apply to immaterial items.

Restatement of the initial balance sheet (the balance sheet as of the beginning of the first year for which income statement amounts are presented) and financial information presented for subsequent periods generally will involve a form of the sequential process shown below:



This booklet combines analysis of the Statement's provisions and some guidelines to aid in adopting the prescribed financial accounting and reporting standards. Some companies have indicated an intention to adopt the accounting prescribed by the Statement prior to the effective date, but believe that certain of the adjustments required for retroactive restatement cannot be made by their reporting deadline for 1977. Piecemeal adoption of the provisions of the Statement is generally inappropriate.

IDENTIFICATION OF CAPITALIZABLE COSTS

The Statement requires capitalization of costs incurred for (1) acquisition of properties, (2) successful exploratory and exploratory-type stratigraphic test wells, (3) development of properties (including development dry holes and development-type stratigraphic test wells), (4) support equipment and facilities and (5) uncompleted wells, equipment and facilities. All other exploration costs and all production costs are charged to expense as incurred.

Development of capitalizable costs associated with each of the five asset categories involves:

- Identification and classification, as proved or unproved, of properties held at the initial balance-sheet date or thereafter and selection of amortizable units
- Accumulation of acquisition costs
- Classification of wells as exploratory or development
- Identification of uncompleted wells
- Accumulation of other development costs
- Accumulation of costs of support equipment and facilities

Identification and Classification of Properties and Amortizable Units

Properties are defined as mineral interests, both operating and nonoperating, acquired through fee ownership, lease, or other contractual means. Properties are classified as proved or unproved depending upon whether the properties have oil and gas reserves. Unproved properties as well as properties with proved reserves should first be identified by lease or other contractual interest.* The Statement provides for amortizable units defined on a property-by-property basis or on the basis of some reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a field or reservoir. The terms *structural feature* and *stratigraphic condition* are intended to identify a localized geological feature as opposed to the broader terms of basins, trends, plays, areas-of-interest, etc.

If a company has a relatively large number of royalty interests on proved properties whose acquisition costs are not individually significant, they may be aggregated without regard to commonality of geological structural features or stratigraphic conditions. The Statement also provides for subdivision of a property that covers so vast an area (e.g., a foreign lease or concession) that the proved reserves relate to only a portion of the property.

Identifying and classifying all properties and grouping proved properties into amortizable units will involve the combined efforts of the accounting, geological, and oper-

***Many companies are more accustomed to the undeveloped/developed terminology; "undeveloped" properties are distinguished from "unproved" properties in that the former may have proved reserves by virtue of successful exploration efforts on adjacent properties.**

ations staffs. Groupings of proved properties currently used by successful-efforts companies may be appropriate. Groupings used for federal income tax purposes may offer the advantages of having readily available depreciation, depletion, and amortization (DD&A) rates and of having identified significant additions and abandonments. Consideration should also be given to the groupings used by reserve engineers in available reserve studies; additional reserve computations (breakdowns or combinations) may be required.

Accumulation of Acquisition Costs

Acquisition costs are those costs incurred to purchase, lease, or otherwise acquire properties including lease bonuses, recording fees, legal, and other direct costs. Costs of carrying or retaining unproved properties, such as delay rentals, taxes, and the maintenance of land records, are considered exploration costs, not acquisition costs, and are charged to expense as incurred.

The tax- or accounting-basis property records will generally contain the direct acquisition costs to be capitalized. A company should identify the costs now required to be capitalized and restate its acquisition cost balances for the differences between those costs and the costs capitalized under its previous method of accounting. For each year in which a complete set of financial statements is presented, costs not meeting the capitalization criteria should be identified for classification and disclosure by function (see page 18, "Disclosures").

Classification of *Wells as Exploratory or Development*

The Statement classifies oil and gas wells as exploratory or development wells (including stratigraphic test wells,* sometimes referred to as slim-holes or expendable wells) and service wells. A development well is drilled within the proved area of oil and gas reserves to the depth of a stratigraphic horizon known to be productive. A service well is drilled or completed for the purpose of supporting production in an existing field. An exploratory well is a well that is not a development well or a service well; it is drilled to determine whether oil or gas reserves exist rather than to develop proved reserves.

The costs of drilling exploratory wells are to be capitalized pending the determination of whether the well has found proved reserves. If proved reserves are not found, the capitalized costs are charged to expense, net of any salvage value. The drilling and equipping costs of development and service wells are capitalized regardless of whether the well is successful or unsuccessful.

***Stratigraphic test wells may be either exploratory or development in nature, and the use of the terms** *exploratory wells* **and** *development wells* **in this booklet includes related stratigraphic test wells, unless otherwise stated.**

Occasionally an exploratory well may be determined to have found oil and gas reserves, but classification of those reserves as proved cannot be made when drilling is completed. These wells are frequently referred to as "shut-in" exploratory wells. Shut-in exploratory wells that require a major capital expenditure, such as a trunk pipeline, before production can begin may be carried as an asset as long as both of the following conditions are met: (1) the well has found a sufficient quantity of reserves to justify its completion if the required expenditure is made, and (2) drilling of additional exploratory wells is under way or firmly planned for the future. Other shut-in exploratory wells should not be carried as assets for more than one year following completion of drilling, if a determination that proved reserves have been found cannot be made.

For each property or grouping of properties, procedures to determine capitalizable exploration and development costs will include the following:

• Identify the first successful well resulting in proved reserves being attributed to previously unproved properties, and capitalize related equipping and intangible drilling costs (IDC) if borne by the company. For any previous wells on such properties, charge the company's accumulated costs, net of salvage, to expense.

• Review each of the company's subsequent wells on the properties in chronological sequence. Classify as exploratory wells those that were drilled to test an unproved geological structure or stratigraphic condition for the existence of oil or gas reserves. Capitalize the costs of development wells, whether successful or not, and successful exploratory wells; and charge the costs of unsuccessful exploratory wells to expense.

Development dry holes may occur because of a structural fault or other unexpected stratigraphic condition, the inability to define precisely the boundaries of a proved reservoir, or a problem encountered in drilling. A well drilled on a property may be a development well even though no proved reserves have been found on the property by previous drilling. For example, if operations in the immediate vicinity have found proved reserves and the first well drilled on the property is to the same stratigraphic horizon within that proved area, as is often the case with an offset well, the well is considered a development well whether successful or unsuccessful. In order to comply with the Statement it will be necessary to identify and capitalize the related costs of any development dry holes that may have been drilled before the first successful well on the property.

Costs of recompletions generally should be capitalized as development costs. Workovers to sustain a level of production or to return a well to an economic level of production should be charged to expense as production costs.

Although the Statement does not specifically address the possibility, a well could be classified as both exploratory and development. For example, a well drilled through a proved horizon (where completion is expected to be commercially feasible) to a previously untested zone may be development in nature to the proved horizon and exploratory beyond that depth. Drilling costs should be allocated to the development and exploratory stages of the operation, and the exploration costs should be charged to expense if the deeper horizon proves unsuccessful.

The combined efforts of a company's geological, exploration, and operations staffs will be required to determine the sequence and the classification of the wells drilled. The specific criteria used to classify wells as exploratory or development should be identified and used by the geological staff in its review of the drilling and land records.

The simplest approach to restating exploratory and development well costs should be used; for example, if a company's procedures presently comply with the Statement with the sole exception of having charged development dry holes to expense, then only a review for and capitalization of such drilling costs will be necessary.

Identification of *Uncompleted Wells*

Drilling costs of wells in progress should be capitalized pending, in the case of exploratory wells, the determination of whether proved reserves are found. The drilling in progress at the initial balance-sheet date and at each balance-sheet date thereafter should be identified, using available accounting or operations records. Unsuccessful exploratory wells should be charged to expense, net of salvage, in the period in which they are determined to be unsuccessful. However, if information was available (i.e., the well was unsuccessful) after the end of a period covered by financial statements but before those financial statements were issued, it should be considered in the accounting for the well costs as of the balance-sheet date.

Accumulation of Other *Development Costs*

Other development costs include:

- Depreciation and applicable operating costs of support equipment and facilities
- Costs incurred to gain access to and prepare development well locations for drilling, including those of clearing ground, road building, and power lines
- Costs incurred to acquire, construct, and install production facilities such as flow lines, separators, heaters, treaters, storage tanks, natural-gas cycling and processing plants, and utility and waste-disposal systems
- Costs incurred to provide improved recovery systems
- Costs of service wells such as injection or disposal wells

In order to compute amortization and depreciation these costs should be accumulated by amortization unit, and capitalizable additions subsequent to initial production should be identified as to amount and timing.

Accumulation of Costs of Support Equipment and Facilities

Other capitalizable items not specifically identified with an individual property are referred to as support equipment and facilities. Support equipment and facilities include seismic and drilling equipment; vehicles; and division, district, or field offices. The support equipment and facilities should be segregated by function, and their depreciation and applicable operating costs become an exploration, development, or production cost, as appropriate. A field office may be located in an area involved in both exploration and production, in which case the depreciation and operating costs of that field office should be allocated between exploration and production costs. Depreciation and operating costs of support equipment and facilities involved in only one function should be allocated entirely to that function.

Other

A company sometimes conducts geological and geophysical studies and other exploration activities on a property owned by another party in exchange for an interest in the property if proved reserves are found, or reimbursement by the owner if proved reserves are not found. In that case, the company conducting exploration work accounts for those costs as a receivable when incurred. If proved reserves are found, the receivable becomes the cost of the proved property acquired.

NONCAPITALIZABLE COSTS

Some expenditures previously capitalized in accordance with prior accounting practices should now be charged to expense. Exploration and production costs that cannot be capitalized include:

- Exploration costs:

  Depreciation and applicable costs of support equipment and facilities, if related exploratory drilling is unsuccessful

  Costs of drilling and equipping, net of salvage, exploratory dry holes

  Geological and geophysical (G&G) costs such as the salaries and expenses of G&G personnel

  Dry-hole and bottomhole contributions

  Costs of carrying and retaining undeveloped properties, such as delay rentals and ad valorem taxes

  Maintenance of land and lease records

- Production (lifting) costs:

  Depreciation and applicable operating costs of support equipment and related facilities

  Costs of labor, materials, supplies, fuel, and services used in operating the wells and related equipment and facilities

  Repairs and maintenance

  Property and severance taxes and insurance

Noncapitalizable costs should be charged to expense as incurred and classified as either exploration or production costs.

MINERAL PROPERTY CONVEYANCES

The Statement establishes standards of accounting for various mineral property conveyances (conveyances) common to the oil and gas industry. Much of the prescribed accounting is already dominant in the industry. In order to assure compliance with the prescribed accounting for conveyances, a company should:

- Review the accounting standards prescribed by the Statement.

- Identify conveyances affecting properties held at the initial balance-sheet date or entered into thereafter for which present accounting policies differ from those prescribed by the Statement.

- Apply the new accounting standards to applicable conveyances.

The Statement requires a gain or loss to be recognized on a conveyance unless the transaction involves either:

- A transfer of assets used in oil and gas producing activities (including both proved and unproved properties) in exchange for other assets also used in oil and gas producing activities, or

- A pooling of assets in a joint undertaking intended to find, develop, or produce oil or gas from a particular property or group of properties.

A gain cannot be recognized (but a loss, if any, should be recognized) at the time of conveyance if:

- A part of an interest owned is sold and substantial uncertainty exists about recovery of the costs applicable to the retained interest, or

- A part of an interest owned is sold and the seller has substantial obligation for future performance, such as an obligation to drill a well or to operate the property without proportional reimbursement for that portion of the drilling or operating costs applicable to the interest sold.

Other aspects of the transaction (for example, conveyances between related parties or lack of economic substance) may prohibit gain or loss recognition under accounting principles applicable to enterprises in general; also, costs of unproved properties are always subject to an assessment for impairment.

For companies with any of these conveyances, the Statement specifies the reserve estimates and production data to be included in determining depreciation, depletion, and amortization rates and in making required disclosures. Generally, a company should include reserves and production in which it has a direct financial interest. The accounting prescribed for some of the more common conveyances is described in Appendix A.

DISPOSITION OF CAPITALIZED COSTS

Impairment Tests

The Statement requires that a company periodically assess its unproved properties to determine if a partial or total impairment in value has occurred. This may accelerate loss recognition for many companies. Impairment losses are recognized by providing a valuation allowance which is offset against capitalized costs of unproved properties. The Statement does not change current generally accepted accounting principles for determining impairment of productive assets.

Procedures to assess unproved properties for impairment will generally include the following:

- Determine unproved properties that may be aggregated to test for impairment.
- Identify the events that will evidence impairment.
- Review unsuccessful exploration efforts conducted on and in the vicinity of the company's properties during periods for which income-statement amounts are presented.
- Review unproved properties as of the current balance-sheet date.

The Statement requires that individual unproved properties whose acquisition costs are relatively significant be assessed on a property-by-property basis. However, if a company has a relatively large number of unproved properties whose acquisition costs are not individually significant, aggregations of properties (in groups or in total for the company) may be made for the purpose of assessing impairment. In this case, impairment provisions are to be determined, by amortizing the properties either in the aggregate or by groups, on the basis of the company's experience in similar situations, the primary lease terms of the properties and the average holding period of unproved properties.

Several types of events that may indicate an impairment in value has occurred include negative indications from seismic work after lease acquisition, unsuccessful drilling efforts on adjacent tracts with the same geological formation, dry holes drilled and no plans to continue drilling, or imminent expiration of a lease term if drilling activity has not commenced on the property. Impairment of a property is probable when a company chooses not to invest additional funds, and the recovery of costs by a farm-out or sale of the property is not likely.

A company applying the impairment test for the first time should assess unsuccessful exploration efforts occurring during each of the periods for which restated income-statement amounts are presented. The purpose of this assessment is to determine whether total or partial impairment should be recognized retroactively in periods prior to the abandonment of the properties. For this purpose, a company can use exploration records, including any pertinent memorandums included in the lease files.

Application of the impairment test to unproved properties at the current balance-sheet date requires assessment by both financial management and exploration personnel. Reports on specific properties provided by persons in a position to know the current status of exploratory efforts should be reviewed and acted upon in the light of the impairment criteria.

If properties for which a valuation allowance has been provided on a property-by-property basis later become producing, the impaired value should not be reinstated, and the property acquisition cost, net of the related valuation allowance, should be reclassified to proved properties. The Statement provides that gross property-acquisition costs should be reclassified without disturbance of the valuation allowance if such allowance results from provisions computed on a group or aggregate basis rather than a property-by-property basis.

Abandonments

Surrender or abandonment of unproved properties is accounted for by charging capitalized acquisition costs to the related allowance for impairment; if an allowance for impairment had not been provided or is inadequate, a loss should be recognized.

Abandonments or retirements of proved properties may involve an entire property constituting an amortization base or only part of the property, such as an item of equipment, an individual well, or a lease. Gain or loss should be recognized on the abandonment or retirement of an entire proved property and when the last well of an amortization unit is abandoned. Ordinarily, gain or loss should not be recognized on partial abandonments or retirements; rather, the capitalized cost of the asset being abandoned or retired should be charged to accumulated depreciation, depletion and amortization (DD&A). An exception to the accounting for partial abandonments and retirements occurs and a loss should be recognized when a partial abandonment or retirement results from a catastrophic event or other major abnormality.

The prescribed accounting for the surrender or abandonment of properties can be applied after identification of:

- Partial abandonments of proved properties that have capitalized costs at the initial balance-sheet date or thereafter
- Abandonments of properties that were charged to accumulated DD&A computed on aggregations of assets (full-cost pools) as of the initial balance-sheet date
- Abandonments of entire properties that occurred during periods for which restated income-statement amounts are to be presented

If accounting records do not exist or are not in sufficient detail to allow identification of specific properties or parts of properties surrendered, abandoned or retired, other sources, including property schedules filed with tax returns, well files, and land records, can often provide the amounts and time of abandonments. In addition, joint-interest billings and authorizations for expenditures that detail abandonment costs may be useful.

Dismantlement Costs and Salvage Values

Enhanced environmental concerns and increasingly complex and expensive operations, especially those offshore, have resulted in commitments for significant dismantlement and restoration costs. These costs include not only expenditures required to remove platforms, equipment, and gathering and storage facilities, but also costs of restoring the environment (land or seabed) to its predrilling state.

The Statement requires that estimated dismantlement, restoration and abandonment costs, as well as estimated residual salvage values, be taken into account in determining amortization and depreciation rates, but is silent concerning the reporting for any related commitments. The charge for these costs, computed by the unit-of-production method, should be included in the determination of net income for all periods during which the subject property produced and a credit made to an appropriate balance-sheet account.

If a company believes it may face significant dismantlement, restoration and abandonment costs, qualified in-house or independent personnel should prepare cost estimates in sufficient detail to assure that all significant costs are considered. These estimates should be reviewed periodically. Industry literature on this topic may provide guidance as to the reasonableness of cost estimates.

Depreciation, Depletion, and Amortization

The Statement provides that DD&A be computed by the unit-of-production method based on proved reserves for acquisition costs and on proved developed reserves for capitalized exploratory drilling and development costs, although it may be more appropriate, in some cases, to depreciate natural gas cycling and processing plants by a method other than the unit-of-production method. In addition, depreciation methods for support equipment and facilities are prescribed.

Restatement of DD&A and depreciation of support equipment and facilities requires:

- Production and estimates of oil and gas reserves for each amortization unit
- Estimates of useful lives for support equipment and facilities
- DD&A rates for capitalized exploratory drilling and development costs and depreciation rates for support equipment and facilities

The Statement defines reserves as proved, proved developed, and proved undeveloped. These definitions were previously adopted by the SEC and closely coincide with definitions commonly used in the industry, and should be read in their entirety. Each company will need to review the definitions previously used in developing its reserve estimates for consistency with the Statement; modifications of the estimates (and DD&A rates) may be necessary if the definitions are not consistent.

Proved reserves, proved developed reserves and cumulative production will be needed as of the initial balance-sheet date; production and reserve estimates will be needed for each of the following years. DD&A rates for prior years should be based on the reserve estimates used in those years; the Statement prohibits the retrospective use of currently revised reserve estimates.

Companies may encounter problems in using previously prepared reserve studies that do not show proved and proved developed reserves separately. One of these classifications is generally presented in reserve studies, and the other can be identified by adding or subtracting proved undeveloped reserves.

Depreciation of support equipment and facilities should be based on the estimated useful lives of the equipment and facilities. If support equipment and facilities serve a single property or group of properties, and if the equipment or facilities have no alternative future uses and have estimated useful lives at least as long as the property's productive life, depreciation should be based on the productive life of the property served.

Most companies will need to develop new DD&A rates. Those companies that define properties on the same basis as used for previous successful-efforts accounting or on the same bases as was used in prior years' income tax returns will have some DD&A rates available. However, companies previously on full-cost accounting may have to segregate reserves and production among property units not previously recognized. Further, the reserve bases used to determine DD&A rates are different for acquisition costs and for capitalized exploratory drilling and development costs.

If a property's reserves and production are predominantly oil or gas, after conversion into a common unit of measurement, the predominant mineral may be used for computing the DD&A rate. However, if neither oil nor gas is the dominant mineral, or if the relative proportion of gas and oil extracted in the current period is not expected to remain reasonably constant throughout the remaining productive life of a property (for example, gas may be the dominant reserve, but only oil may be produced pending tie-in to a gas pipeline), reserves and production should be translated into a common unit of measurement for the DD&A rate computation. Translation should be based on "relative energy content," which can vary significantly with the BTU content of the minerals being produced, but which is generally recognized as about 6 MCF of gas equal to one barrel of oil.

Major property additions and recompletions should be separately considered in relation to reserves remaining at the time the additional costs were incurred. This is particularly important because accumulated DD&A at the initial balance-sheet date should be the same as would result if the annual DD&A rates were separately applied to restated property balances for each of the years prior to that date.

If a company has a relatively large number of royalty interests whose acquisition costs are not individually significant, they may be aggregated for the purpose of computing amortization without regard to commonality of geological structural features or stratigraphic conditions; if information is not available to estimate reserve quantities applicable to royalty interests owned, a method other than the unit-of-production method may be used to amortize their acquisition costs.

If significant development costs (such as the cost of an offshore production platform) are incurred in connection with a planned group of development wells before all of the planned wells have been drilled, a portion of those development costs should be excluded in determining the unit-of-production amortization rate until the additional development wells are drilled. Similarly, it is necessary to exclude, in determining the amortization rate, those proved developed reserves that will be produced only after significant additional development costs are incurred, such as for improved recovery systems.

INCOME TAXES

The Statement requires comprehensive interperiod income tax allocation by the deferred method; that is, a company must retroactively provide deferred income taxes on revenues or gains and expenses or losses that enter into the determination of taxable income and pretax accounting income in different periods. These differences are called "timing differences," and examples include IDC deducted for tax but capitalized for books, G&G costs capitalized for tax but charged to expense for books, and delay rentals which are sometimes capitalized for tax but charged to expense for books. Recognition of the interaction of timing differences with any anticipated future excess of statutory depletion allowed as a tax deduction over cost depletion otherwise allowable as a tax deduction is expressly prohibited by the Statement.

For a full understanding of the complexities of accounting for income taxes, a company should review APB Opinion No. 11, *Accounting for Income Taxes,* and related pronouncements. Procedures to provide for deferred income taxes will generally include the following:

• Identify types of timing differences.

• Select either the "gross-change" or "net-change" method for determining the tax effects of timing differences.

• Determine amounts of timing differences as of the initial balance-sheet date and for each period thereafter.

• For each period to be restated apply the selected method to determine the tax effect of the timing differences.

As a result of the Tax Reduction Act of 1975 and the issuance of FASB Statement No. 9, *Accounting for Income Taxes—Oil and Gas Producing Companies,* most companies will have already identified the types of timing differences. However, accounting changes required by the Statement may create new timing differences (e.g., G&G costs which must be charged to expense for book purposes), may eliminate differences that previously existed (e.g., delay rentals which must be charged to expense for book purposes) or may require recognition of timing differences arising prior to the implementation dates of previous related pronouncements. Identification of the types of timing differences generally will involve analysis of prior years' tax returns and financial accounting policies.

Either the "gross-change" (arising and reversing timing differences of the same type are separately identified and considered in the deferred tax provision) or the "net-change" (only the net change in amounts of similar types of timing differences are considered) method for determining the tax effects of timing differences will need to be adopted if a company has not previously accounted for deferred income taxes.

Companies should exercise care in adopting any "short-cut" method of determining the amounts of timing differences; however, the following suggestions may be of assistance in approximating the amounts of some common timing differences (IDC; depreciation; and G&G, leasehold, and other property-acquisition costs):

• Cumulative timing differences for IDC would be the same as the restated net book balance of IDC at the initial balance-sheet date if IDC were deducted as incurred for income tax purposes and capitalized for book purposes. For subsequent years, IDC deducted on the tax return less book amortization of IDC constitutes the timing difference.

• Cumulative timing differences for depreciation can be determined by comparing net restated book and net tax bases in equipment as of the initial balance-sheet date. Subsequent years' differences can be derived by comparing restated book depreciation with tax depreciation.

• Cumulative timing differences for G&G, leasehold, and other property acquisition costs can be determined by comparing the net restated book and net tax bases in the related mineral properties as of the initial balance-sheet date, if the "tax-preference" method is adopted for determining the amounts of these types of timing differences. For subsequent years, the newly arising timing difference for G&G, leasehold and other property-acquisition costs can be determined by comparing the costs capitalized for book and tax purposes each year.

Under the "tax-preference" method, statutory (allowable) depletion in excess of book depletion is considered a timing difference until the tax-cost bases in the G&G, leasehold, and other property acquisition costs have been fully depleted; thereafter statutory (allowable) depletion is considered a permanent difference.

The determination of the timing differences as of the initial and subsequent balance-sheet dates by a method other than the "tax-preference" method would generally require extensive recalculations and would make the turnaround of such timing differences dependent in part on future excess percentage depletion—a seemingly anomalous condition.

As a general rule, the statutory income tax rates in existence when timing differences arise should be used in determining the applicable deferred income taxes. The Statement, however, indicates that the use of estimates and approximations may be required in retroactive restatements. For example, companies may find it is reasonable to use weighted-average tax rates in approximating the cumulative deferred income taxes as of the initial balance-sheet date.

The interaction of the following items with deferred income taxes is complex, and their presence will require further consideration in determining deferred income tax provisions:

- Timing differences involving capital gains
- Transfers of properties having different bases for book and tax purposes
- Net operating losses, investment tax credits and foreign-tax credits

Other unusual items or situations may be encountered that could also have an effect on the determination of deferred income tax provisions.

DISCLOSURES

The Statement requires disclosures of reserve quantities, capitalized costs, and the classification, by function, of costs incurred during each year for which a complete set of financial statements is presented. Disclosure of capitalized costs should also be included in a complete set of interim financial statements. Disclosures of reserve quantities and of costs incurred are not required in interim financial statements, although disclosure of information regarding favorable or adverse events significantly affecting reserve data reported in the most recent annual financial statements is encouraged. Reference to the Statement should be made to determine that the information necessary to meet the disclosure requirements is developed concurrently with the restatement of the financial statements. These disclosures should be consistent with other financial-statement disclosures. For example, disclosures of identifiable assets and other items by geographic segment should be consistent with disclosures required by the Statement of costs incurred in each geographic area for which reserve quantities are disclosed.

Reserve Quantities

The following disclosures are required for each year for which a complete set of financial statements is presented:

- Net quantities of proved and proved developed reserves as of the beginning and end of each year
- Changes in net quantities of proved reserves during each year, including revisions of estimates; improved recovery; production; purchases or sales of minerals-in-place; and extensions, discoveries and other additions

The disclosures should be segregated by type of reserve (oil or gas) and by home country and each foreign geographic area in which significant reserves are located. Net reserve quantities include both operating and non-operating interests, all of the quantities attributable to consolidated companies, and the company's share of the reserves of any investee that is proportionately consolidated. Quantities attributable to an investor's share of the reserves of an investee accounted for by the equity method are excluded but should be separately disclosed. Reserve quantities attributable to royalty interests owned may be excluded if the information regarding such quantities is unavailable. If excluded, that fact and the company's share of oil and gas produced for those royalty interests should be disclosed.

Net reserve quantities exclude oil or gas subject to long-term supply, purchase or similar agreements and contracts (e.g., production-sharing contracts), including such agreements with foreign governments and authorities. The net quantities received under such agreements during each year should be separately disclosed if the company participates in the operation of the property in which the oil or gas is located or otherwise serves as producer of the oil or gas.

In addition, economic or other factors that might significantly affect the value of the reserves should be disclosed. Examples include contractual obligations restricting the selling price of a significant portion of reserves, unusually high expected lifting costs, or the necessity to build a major pipeline or other facilities before production can begin.

Capitalized Costs

The Statement does not generally change disclosure requirements for capitalized costs as established by APB Opinion No. 12, *Omnibus Opinion—1967.* The aggregate amount of capitalized costs and related accumulated DD&A and valuation allowances should be reported as of the end of each period for which a complete set of interim or annual financial statements is presented. It may often be appropriate to disclose separately the amount of capitalized costs for major classes of depreciable assets (or combinations thereof) by nature (e.g., mineral interests in properties, wells and related equipment and facilities, support equipment and facilities, and drilling in progress) or by function (e.g., acquisition, exploration, and development).

Costs Incurred

For each year for which a complete set of financial statements is presented, costs incurred during the period, whether capitalized or charged to expense, should be segregated and disclosed by type of cost, i.e., acquisition, exploration, development, or production. Exploration, development, and production costs include allocable depreciation of support equipment and facilities and do not include expenditures to acquire the support equipment and facilities. Conversely, DD&A of capitalized acquisition, exploration, and development costs cannot be included in production costs, since the expenditures for these capitalized costs are included under their appropriate functional classifications. Separate disclosure is required of costs incurred in the home country and in each geographic area for which reserve quantities are disclosed.

Disclosures Proposed by the SEC

The SEC has proposed certain disclosure rules in addition to those included in the Statement that would require (1) disclosure of capitalized costs by asset categories and major geographic area, (2) segregation of costs incurred by functional categories between amounts capitalized and amounts charged to expense as incurred, and (3) disclosure of the present value of estimated future production of proved reserves and estimated costs to complete development of proved reserves.

An SEC-reporting company will need to consider the rules that are ultimately adopted by the SEC in developing its financial-statement disclosures. In addition, the Department of Energy is presently developing a petroleum company financial reporting system (FRS) which may require more detailed disclosures.

ESTIMATING THE GENERAL MAGNITUDE OF FINANCIAL-STATEMENT EFFECTS

In September 1977, the SEC issued Staff Accounting Bulletin No. 16 which described the Staff's position that disclosures in SEC filings by companies whose financial statements would be significantly changed by subsequent retroactive application of the exposure draft of the Statement should include an indication of the estimated general magnitude of the potential effects on reported shareholders' equity and earnings and the implications, if any, on the ability to comply with covenants in debt or other agreements. Companies not reporting to the SEC will want to consider disclosure of these potential effects in their financial statements.

Each company should estimate the potential effects in the light of its particular operations and accounting policies; areas on which to focus early attention generally will include the following:

- Exploratory dry holes and unsuccessful exploratory-type stratigraphic test wells previously capitalized
- Development dry holes and development-type and successful exploratory-type stratigraphic test wells previously charged to expense
- Impairment of unproved properties and exploratory wells shut in for more than one year
- Lease rentals and G&G and other exploratory costs, if any, previously capitalized
- Mineral property conveyances and sales, surrender, abandonment, or retirement of properties
- Adjustment of DD&A rates to comprehend estimated dismantlement, restoration and abandonment costs and estimated residual salvage values

- Adjustment to base DD&A rates for acquisition costs on proved reserves and for capitalized exploratory drilling and development costs on proved developed reserves

- Deferred income taxes on timing differences such as IDC, lease rentals, G&G costs, depreciation, etc.

Companies may encounter significant problems in accumulating the data to estimate these effects within the time constraints for release of financial statements initially following the issuance of the Statement. Accordingly, descriptions in terms of broad ranges or percentages should be acceptable until data permitting a more complete quantification of the estimated effects are developed. The disclosure should indicate that the estimates may be subject to revision for such later information or for other matters, as appropriate.

APPENDIX A

Accounting for Mineral Property Conveyances

The accounting prescribed for some of the more common conveyances is as follows:

- *Carved-out production payments measured in terms of production—Setter* does not record gain or loss at the time the interest is created; funds received are recorded as unearned revenue to be recognized as production is delivered. Purchaser records the production payment as an interest in a mineral property at cost and amortizes it by the unit-of-production method as production is received.

- *Carved-out production payments measured in cash and purchaser advances*—These transactions are essentially financing arrangements because production payments are repayable in cash out of the proceeds from a specified share of future production of a producing property until the amount advanced plus interest at a specified or determinable rate is paid in full; the purchaser advances are repayable by offset against purchases of oil or gas discovered from the exploration financed, or in cash if insufficient oil or gas is produced by a specific date. Funds advanced are treated as a liability by the recipient and as a receivable by the party making the advance.

- *Farm-ins, farm-outs—F*armor's original cost becomes the cost of interest retained (no gain or loss recognized). Farmee does not have acquisition costs and accounts for incurred exploration, development, and operating costs in accordance with the Statement. Neither farmor nor farmee makes any reclassifications of costs upon payout of a reversionary interest.

- *Free-well deals*—Essentially the same as for farm-ins and farm-outs. Assignor records no cost for the obligatory free well; assignee has no acquisition costs and follows the prescribed accounting for incurred exploration (including G&G, if required by the assignment), development, and operating costs in accordance with the Statement.

- *Carried interests*—Carried party (assignor) makes no accounting until after recoupment (payout) of the carried costs by the carrying party (assignee), at which time the carried party begins accounting for its share of revenue, expenses, and subsequent development costs that are to be shared. Carrying party follows the prescribed accounting for costs incurred and revenues (including carried portions during payout). Carried costs incurred by the carrying party may be separately amortized over reserves attributable to the carried interest only, or grouped with all of the carrying party's costs and amortized over the sum of reserves attributable to the carried interest plus the carrying party's original interest in reserves.

- *Unitizations*—Cash received (paid) by participants as an equalization of investments is deducted from (added to) the investments in wells and related equipment and facilities contributed to the unit.

- *Exchanges of parts of operating interests in properties*—Neither party recognizes a gain or loss on the transaction. Each party accounts for its own costs in accordance with the Statement, although the interest acquired may be disproportionate to the costs borne.

- *Sales of entire or partial interests in proved properties*—Difference between sales proceeds and unamortized cost is recognized as a gain or loss. Sale of a partial interest requires that unamortized costs be apportioned on the basis of fair values between the interest sold and the interest retained. However, the sale of a partial interest in or of an entire proved property constituting a part of an amortization base may be accounted for as a normal retirement with no gain or loss recognized, but only if doing so does not significantly affect the unit-of-production amortization rate.

- *Sales of entire interests in unproved properties—A* gain or loss is recognized based on sales proceeds compared with the original cost of the property or cost less valuation allowance if impairment was individually assessed (not on a group basis) for that property. No gain or loss is recognized on property for which a valuation allowance has been provided on a group basis, unless the sales price exceeds the original property cost, in which case the resulting excess is recognized as a gain.

- *Sales of partial interests in unproved properties*—Sales proceeds are treated as a recovery of cost, with a gain recognized only if proceeds exceed the original cost of the entire property, or cost less valuation for impairment if such valuation was individually assessed for that property.

- *Sales of operating interests in proved properties with a nonoperating interest retained—Gain* or loss is recorded on the difference between proceeds and cost of the operating interest sold. Cost is apportioned to the operating interest sold and the nonoperating interest retained based on fair values of those interests.

- *Sales of proved properties subject to a retained production payment—The* sale of a proved property that is subject to a retained production payment expressed as a fixed sum of money payable only from a specified share of production from that property, with the purchaser obligated to incur the future costs of operating the property, is recorded as a sale, with recognition of gain or loss, if satisfaction of the retained production payment is reasonably assured. The retained production payment is recorded as a receivable, with interest accounted for in accordance with the provisions of APB Opinion No. 21, *Interest on Receivables and Payables.* The purchaser records as the cost of the assets acquired the cash consideration paid plus the accrual for the present value (determined in accordance with APB Opinion No. 21) of the retained production payment. If satisfaction of the retained production payment is not reasonably assured, or if the retained production payment is expressed as a right to a specified quantity of oil or gas out of a specified share of future production, the transaction is accounted for as the sale of an operating interest in a proved property with a nonoperating interest retained.

APPENDIX B

*Definitions**

Development well. A development well is a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Exploratory well. An exploratory well is a well that is not a development well, a service well, or a stratigraphic test well as those terms are defined herein.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

Proved area. The part of a property to which proved reserves have been specifically attributed.

Proved developed reserves. Reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. Proved developed reserves include both (a) proved developed *producing* reserves (those that are expected to be produced from existing completion intervals now open for production in existing wells) and (b) proved developed *nonproducing* reserves (those that exist behind the casing of existing wells, or at minor depths below the present bottom of such wells, which are expected to be produced through these wells in the predictable future, where the cost of making such oil and gas available for production should be relatively small compared to the cost of a new well). Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves. Those quantities of crude oil, natural gas, and natural gas liquids which, upon analysis of geologic and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions. Proved reserves are limited to those quantities of oil and gas which can be expected, with little doubt, to

*These definitions are taken from the glossary appended to the Statement.

be recoverable commercially at current prices* and costs, under existing regulatory practices and with existing conventional equipment and operating methods. Depending upon their status of development, such proved reserves are subdivided into "proved developed reserves" and "proved undeveloped reserves."

Proved undeveloped reserves. Reserves which are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units, which are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Service well. A service well is a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane, or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

Stratigraphic test well. A stratigraphic test is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. For purposes of this Statement, stratigraphic test wells (sometimes called "expendable wells") are classified as follows:

> ***Exploratory-type stratigraphic test well.*** A stratigraphic test well not drilled in a proved area.
>
> ***Development-type stratigraphic test well.*** A stratigraphic test well drilled in a proved area.

*The term *current prices* is elaborated on by the SEC in *Securities Act Release No. 5837* as follows: "Current prices include consideration of changes in existing prices provided by contractual arrangements, by law, or by regulatory agencies, where applicable; and for changes in prices for gas to be produced subsequent to termination or expiration of existing contracts, which latter prices should be based on current prices plus escalation for similar production subject to the entity's or other entities' recent contracts." The term "escalation" is further elaborated on in *SEC Release No. 5877* as follows: "The 'escalation' referred to in these releases is limited to specific escalation provisions in recent contracts. Escalations to reflect future price expectations are not permitted."

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